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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-005 Application 15-07-006 Application 15-07-007 Application 15-07-008

PROTEST OF THE OFFICE OF RATEPAYER ADVOCATES

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I. INTRODUCTION

Pursuant to Rule 2.6(a) and (c) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the Office of Ratepayer Advocates ("ORA") submits this Protest to the following consolidated applications:

- *Application of Southern California Edison Company (U338E) for the Approval of its Distribution Resources Plan (A.15-07-002).*
- *Application of San Diego Gas and Electric Company (U902E) for Approval of Distribution Resource Plan (A.15-07-003).*
- *In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769 (A.15-07-005).*
- *In the Matter of the Application of Pacific Gas and Electric Company (U 39 E) for Adoption of Its Electric Distribution Resources Plan Pursuant to Public Utilities Code Section 769(A.15-07-006).*
- *Application of Liberty Utilities (CalPecoElectric) LLC (U933E) for Approval of Its Distribution Resources Plan (A.15-07-007).*
- *In the Matter of the Application of Golden State Water Company on Behalf of its Bear Valley Electric Service Division (U913E) for Approval of its Distribution Resource Plan (A.15-07-008).*

ORA files this Protest pursuant to its statutory mission to obtain the lowest possible utility rates consistent with reliable and safe service levels. This Comment is timely filed in compliance with the *Administrative Law Judge's Ruling 1) Consolidating Proceedings; 2) Setting Prehearing Conference, and Granting Motion for Extension of Time* (ALJ Ruling), which extended the Protest deadline from August 3, 2015 to August 31, 2015 and consolidated all six applications (Consolidated Applications).[1] The Consolidated Applications seek approval of distributed resource plans (DRPs), which create a framework to further integrate distributed energy resources (DER) onto the distribution grid.

[1] ALJ Ruling, pp. 2-5.

II. BACKGROUND

The Consolidated Applications request approval of DRPs for PacifiCorp, Liberty Utilities, and Bear Valley Electric – also called the Small and Multi-Jurisdictional Utilities (SMJUs) -- as well as Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company ("SDG&E") (the IOUs). The *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning* (ACR), dated February 6, 2015, clarified that SMJUs were required to file simplified DRPs which met the five statutory requirements of Public Utility Code (P.U. Code) Section 769, including the following:

1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation,
2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives,
3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources,
4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers, and
5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.[2]

The IOUs were required to file detailed DRPs in compliance with P.U. Code Section 769 as well as the ACR. The ACR identified supplemental goals for the DRP, including the following parallel goals:

The ACR also included the *Guidance for Section 769 – Distribution Resource Planning* (Guidance), which created guidelines for compliance with P.U. Code Section 769(b), including additional requirements for IOU DRPs such as publishing integration capacity maps, creating a

[2] P.U. Code § 769 (b).

consistent locational value analysis, analysis of three DER growth scenarios, implementation of five deployment and demonstration projects and compliance with phasing of next steps.[3]

III. SUMMARY OF ORA'S RECOMMENDATIONS

ORA respectfully submits this Protest and recommends that before approving the IOU and SMJU DRPs, the Commission:

- Create a Tariff Working Group to develop guidelines for incorporating locational value methodology into both demand and supply side tariffs as well as identify combinations of DER packages which can be developed as tariff-s in other proceedings, including the Integrated Demand Side Resources (iDSR)(R.14-10-003), Rule 21 DER Interconnection Process (R.11-09-011) , and Net Energy Metering -(NEM 2.0)(R.14-07-002).Review the reasonableness of demonstration and deployment plans and their associated costs in a separate ratesetting phase or track of the DRP proceeding; the Commission should not grant these plans and costs based on a presumption of reasonableness in a quasi-legislative proceeding. This proceeding will eventually result in ratesetting and may require hearings pursuant to section 454 of the Public Utilities Code to protect ratepayers from unreasonable or excessive costs.
- Review the reasonableness of proposed grid modernization and their associated costs and investments in a ratesetting phase or track of this proceeding; again, the Commission cannot legally approve the grid modernization proposals and costs based on a presumption of reasonableness in a quasi-legislative proceeding.
- Modify the integration capacity analysis to reflect the impact of smart inverter technology.
- Modify the locational value analysis assumption for over-generation to reflect the fact that both conventional and renewable resources can contribute to over-generation conditions at night.
- Require IOUs to rectify deficiencies in their DRP safety sections to substantially comply with the Guidance.
- Form a Data Access working group to discuss data access to address long-term data access challenges.
- Create a phase of the DRP to form a stakeholder working group to develop stakeholder-driven DER procurement policy and mechanism development which IOUs will be ready to implement by 2018 (Phase 2b).
- Form a Distributed Resource Procurement Review Group (DPRG) in order to periodically update nonmarket participants on IOUs application of the distribution deferral framework.

[3] Guidance, pp. 3-5.

IV. DISCUSSION

ORA reviewed the SMJUs and IOU's DRPs and identified the following procedural and substantive issues within the scope of review for this proceeding. In addition to the issues raised in this Protest on the Consolidated Applications, ORA reserves the opportunity to raise additional issues that may be identified as ORA continues its examination and review of the Consolidated Applications.

A. ORA Proposes a Workshop on Grid Architecture Principles.

ORA recommends holding workshops to determine how the IOUs' integration capacity analysis can better meet the objectives of the "More than Smart" vision which states that "California's distribution system planning, design and investments should move towards an open, flexible, and node-friendly network system (rather than a centralized, linear, closed one) that enables seamless DER integration."[4] According to the More than Smart paper, "investments should be based on solid architectural grid principles while ensuring the timing and pace align with customer needs and policy objectives."[5]

> In general, centralized control involves a centrally located computer and SCADA or other communication networks to coordinate automated equipment operations among multiple feeders. In contrast, decentralized controls use local control packages to operate equipment on a single feeder, or on a relatively small number of feeders according to pre-established logic schemes.[6]

ORA is generally supportive of the IOUs' DRPs. However, ORA is concerned that results of the integration capacity and locational value analysis may require distribution grid investments to interconnect DERs at optimal locations on the grid. Under the current distribution network paradigm, IOUs operate under a centralized command and control structure. If these grid investments are solely under IOUs' control, the IOU may still continue to be entrenched in the current centralized command and control paradigm instead of operating under a distribution service operator paradigm that could allow third parties to manage the IOUs'

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[4] ACR, p. 7; *see also* OIR, Appendix B, p. 4.

[5] OIR, Appendix B, p. 4 (emphasis added).

[6] U.S. Department of Energy (DOE), Application of Automated Control for Voltage and Reactive Power Management – Initial Results, Smart Grid Investment Program, (Dec. 2012), p. 8, https://www.smartgrid.gov/files/VVO_Report_-_Final.pdf.

customers' DER. The distribution system operator paradigm should be further explored by the Commission in a workshop.

Hosting a workshop on grid architectural principles allows the Commission to evaluate alternatives outside of the IOU experience. A stakeholder workshop is appropriate in this proceeding because third-party stakeholders, including academics and DER providers, are in the best position to demonstrate how the IOUs could effectively integrate DERs into an "open, flexible and node-friendly network system."[7] A workshop on grid architectural principles will provide the proper forum for the Commission to make an informed decision on the principles around which the 21rst century distribution grid should be organized. Therefore, ORA recommends that the Commission scope the grid architecture workshop as one of the workshops proposed by the IOUs within the quasi-legislative phase of this proceeding.

B. The Commission Should Establish a Stakeholder Tariff Working Group or Other Forum to Create Guidelines to Implement Locational Values Analysis to Tariffs.

Under P.U. Code Section 769, IOUs are required to "propose or identify tariffs, contracts or other mechanisms for the deployment of cost effective distributed resources that satisfy distribution planning objectives." Among other things, the Guidance requires IOUs to make recommendations in their DRPs on how locational values could be integrated with existing tariffs for DERs.[8]

In its DRP, PG&E states that it intends to incorporate locational values into energy efficiency (EE), demand response (DR) and integrated demand-side management resources (iDSR) proceedings.[9] However, PG&E does not provide any detail regarding how it intends to integrate locational values. PG&E only references utility-specific programs that it has control over rather than general guidelines for incorporating locational valuation.

SCE states its intention to rely on solicitations to address locational value.[10] It references existing Commission proceedings as the proper venue for addressing locational valuation in

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[7] ACR, p. 7; *see also* OIR, Appendix B, p. 4.

[8] Guidance, p. 9.

[9] PG&E DRP, p. 170.

[10] SCE DRP, p. 144.

existing tariffs, but offers no suggestion for how to integrate locational valuation into those proceedings or how to integrate valuation for combinations of DER resources.[11]

SDG&E notes that "it is important to take a thoughtful approach to determining [whether tariffs or contacts are] the best mechanism" to incorporating locational values to DER resources.[12] It cautions that incorporating locational benefits into a tariff on a permanent basis may be problematic because, over time, the tariff may stimulate load migration which nullifies the benefits of the DER.[13] SDG&E cites its Vehicle to Grid Integration (VGI) pilot program which utilizes a dynamic price signal as a "structure [which] can provide a framework for consideration of greater integration incentives through retail rates."[14]

The DRPs should provide a framework for incorporating locational values into existing tariffs. By failing to suggest tariffs or incentives other than utility run solicitations and programs in its demonstration and deployment plans, SCE and PG&E sidestep an opportunity to propose tariffs or incentives that would aid DER growth in manner supportive of existing distribution infrastructure. SDG&E provides an example of how dynamic pricing may be used to adjust the incentives of locational valuation over time, but also falls short of providing guidelines for locational value integration to the suite of existing tariffs.

Building on SDG&E's suggestion to create dynamic price signals or direct incentives in its demonstration programs,[15] ORA suggests a Tariff Working Group to develop a robust framework for incorporating locational values into existing tariffs and to propose new DER tariffs which can then be developed in other proceedings such as the iDSR proceeding.[16] For example, specific hosting capacity conditions may trigger locational value incentives for existing tariffed customers in the area such as a one-time incentive for adopting storage in an area with high residential PV penetration. The DRP proceeding is the proper forum to discuss these triggers because the locational valuation methodology, along with its significance, is developed here. A workshop could also develop guidelines for integrating combinations of DER

[11] SCE DRP, p. 144.

[12] SDG&E DRP, p. 104.

[13] *Id.*

[14] *Id.* p. 105.

[15] *Id.*

[16] R.14-10-003.

technologies on both the supply and demand side resources. This type of integrated DER policy development should occur in the DRP because it could not occur in siloed forums such as the existing tariff proceedings. Otherwise, the Commission risks ceding oversight of locational valuation to the IOUs through discretionary contracting within the Request for Offer (RFO) process.

ORA recommends that tariffs are identified in the DRP, where they can consider both supply and demand side resources. A portion of the tariffs related to customer-side programs can be worked out in the iDSR proceeding, which proposed to adopt an expanded scope including the of integrated customer-side tariffs in its proceeding.[17]

C. Demonstration Projects and Deployment Plans.

The Guidance required the IOUs to propose five demonstration and deployment projects "intended to demonstrate integration of locational benefits analysis into Utility distribution planning and operations" (D&D Projects).[18] The IOUs were further instructed to coordinate the proposed D&D Projects with each IOU's smart grid deployment plan and EPIC investment plan. The objectives defining each of the five D&D Projects are:

a) Demonstrate dynamic integrated capacity analysis—Develop a specification for a demonstration project where the utilities' Commission-approved Integration Capacity Analysis methodology is applied to all line sections or nodes within a Distribution Planning Area (DPA);

b) Demonstrate the optimal location benefit analysis methodology—Develop a specification for a demonstration project where the utilities' Commission-approved Optimal Location Benefit Analysis methodology is performed for one DPA;

c) Demonstrate the optimal DER locational benefits—Develop a specification for a demonstration project where at least three DER avoided cost categories or services for which only "normative value

[17] Proposed Decision Adopting an Expanded Scope, a Definition, and a Goal for the Integration of Demand Side Resources, p. 8.

[18] Guidance, p. 6.

date" presently exist can validate the ability of DER to achieve net benefits consistent with the Optimal Location Benefit Analysis;

d) Demonstrate distribution operations at high penetrations of DERs—Develop a specification for a demonstration of high DER penetrations that integrates the utilities' distribution system operations, planning and investment for implementation; and

e) Demonstrate DER dispatch to meet reliability needs—Develop a specification for a demonstration project where the utility would serve as a distribution system operator of a micro-grid where DERs serve a significant portion of customer load and reliability services.[19]

The proposed projects outlined by the IOUs generally meet the criteria set forth in the Guidance. However, the descriptions provided by the IOUs are a very high level overview of the projects, lacking the necessary detail to evaluate each project's merit. For example, there is no cost information associated with any of the projects proposed by PG&E and SCE. SDG&E is the only utility that provided a cost estimate for its D&D Projects. Therefore, it is impossible for ORA to assess the reasonableness of the scope and cost of the projects.

ORA recommends the Commission review of the D&D Projects be under a ratesetting track of this proceeding or, in the alternative, require the IOUs to submit more detailed applications subject to a reasonableness review. The applications should include, among other things, the costs involved for each project, the upgrades required, and discuss merits of the proposed utility projects compared to alternative projects.

Additionally, holding hearings would allow stakeholders to compare the projects across IOUs and recommend modifications. The details of the projects submitted in the DRP are inconsistent across IOUs. As noted above, only SDG&E provided an estimated project cost. On the other hand, SDG&E did not identify a location for its Distribution Operations at High Penetrations of DERs whereas PG&E and SCE did. It is difficult to compare the projects when the proposals lack uniform information.

The Commission should develop a budget and establish a cost cap for each D&D Project. For example, SCE states that the distribution system in the preferred-resources pilot (PRP) area

[19] Guidance, p. 6-7.

proposed for D&D Projects may not support a high level of DER penetration and thus require system upgrades needed to support some of the demonstration projects. SCE further states that it does not know if and what kind of system upgrades may be required to support the demonstrations projects and it will record the revenue requirement associated with incremental costs for these projects into a memorandum account. Approving these projects in this application without a reasonableness review of the projects and their associated costs would essentially provide the IOUs with a blank check without safeguarding ratepayers from excessive and unreasonable costs.

ORA's specific comments on some of the D&D Projects proposed by the IOUs are stated below.

1. Demonstrate Distribution Operations at High Penetrations of DERs

a) PG&E's Huron Substation

PG&E chose the Gates Distribution Planning Area (DPA) to demonstrate Distribution Operations at High Penetration of DERs.[20] The Gates DPA resides at PG&E's Huron Substation, which is located in Fresno County. The Peak Load Penetration[21] in this area is high at 14.4 %.[22] Fresno already has a high penetration of distributed generation (DG) at 316 MW.[23,24] It also has the highest peak load of all the counties. The Huron Substation also has a low Integration Capacity Factor (ICF)[25] of negative 195.[26] PG&E states that when an ICF becomes negative, it means that the DER may be causing issues or is likely to have required mitigations due to interconnection.[27]

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[20] This DPA is also being used for the Dynamic Integration Capacity Analysis and Optimal Location Net Benefit Methodology demonstrations. PG&E DRP, p. 146.

[21] Peak Load penetration is defined as distributed generation divided by the peak load.

[22] PG&E DRP, p. 55.

[23] *Id.*

[24] PG&E listed DG penetration by county. Fresno had the highest DG penetration at 316.1 MW in comparison to all other counties in the PG&E service area.

[25] ICF is a formula to measure the relative capacity on a line; see formula PG&E DPR, p. 51.

[26] PG&E DRP, p. 57.

[27] *Id.* at p. 51.

While this project seems reasonably located based on the project description, ORA requires further information in order to evaluate the reasonableness of costs associated with this D&D plan, such as why the Huron substation was chosen and information regarding any upgrades deferred.

b) SCE's Johanna Jr. Substation

SCE proposes to demonstrate DER distribution operations at high penetrations of DERs by leveraging the equipment and resources installed as part of the Preferred Resource Pilot (PRP) and Integrated Grid Project (IGP) in the vicinity of the Johanna Jr. Substation area, located in Orange County. However, SCE provides neither details regarding the leveraged equipment or resources nor cost information. SCE also states that it may need to make system upgrades to support the demonstration project but provides no details or cost information on the proposed system upgrades.

The merits of using the IGP area at the Johanna Jr. substation for its Distribution Operations at High Penetrations of DERs project need to be further explored. ORA needs additional information to determine the project reasonableness, such as the level of DER penetration already present at this substation. Since SCE did not identify the Johanna Jr. Substation as being in the top 1% of Distribution Circuits with High Levels of DG Penetration, SCE should explain why the Johanna Jr. substation should be considered for this project instead of one of the substations listed it its top "1% of Distribution Circuits with High Levels of DG Penetration" list.[28]

SCE should also identify the level and cost of its proposed system upgrades. Additionally, SCE should explain how these upgrades and leveraging the PRP and IGP is a better investment than conducting the demonstration project in an area that already has high levels of DG penetration and where upgrades may not be needed.

c) SDG&E's Substation Project

SDG&E plans to install smart inverters, dynamic voltage controllers (DVC), community ES, and power regulating transformers at an estimated cost of $9.4 million.[29] SDG&E ideally

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[28] *See* SCE DRP, App. E.

[29] SDG&E DRP, p. 81.

plans to deploy the DER and grid reinforcement technology on a circuit "that has low load levels and a high PV penetration."[30]

To assess this proposal, ORA requires more information to determine the reasonableness of this project, such as identifying a substation location. Additionally, SDG&E lists Power Regulating Transformers and Dynamic Voltage Controllers as part of the DER installations it will test.[31]

2. Demonstrate DER Dispatch to Meet Reliability Needs.

a) PG&E Should Submit a Budget Which Demonstrates the Cost Effectiveness of the Cable Deferral Project in Order for ORA to Complete its Reasonableness Review.

Angel Island is a small, sparsely inhabited island located in the San Francisco Bay, operated as a recreational area by the National Park Service. It also houses approximately 20 full time residents and has a peak demand of around 100 kW.

PG&E proposes to create a micro-grid on Angel Island which would dispatch DERs in lieu of replacing the failing underwater cable currently providing electricity to the island. PG&E expects that the optimal DER portfolio will run 24x7x365 to maximize the benefits of the DERs and reduce dependency on the cable. PG&E also states that park management would also like to consider replacing its conventional-fuel tourists' shuttles and work vehicles with electric-powered equivalents in order to mitigate the risk of transporting flammable diesel fuel onto the island via ferry.

ORA generally supports the Angel Island project as a useful demonstration project to show DER deployment for reliability purposes. If the underwater cable project is deferred, Angel Island will solely rely on DERs for their electricity needs and thus clearly show the reliability of DERs in providing electricity without relying on the grid. Since the peak load on the island is only 100 kW, the Angel Island micro-grid will be a useful way to test the effectiveness of DERs to meet reliability needs because one small change in load could potentially be a relative large percentage of change in system usage.

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[30] SDG&E DRP, p. 78.

[31] *Id.* at p.79-80.

Angel Island could also be an ideal place to test vehicle-to-grid or vehicle-to-home technology as the residents will solely rely on DERs during night time hours. Additionally, this would test the reliability of DERs to charge electric vehicles without connecting to the main grid. If this project is to proceed, ORA recommends PG&E leverage funding from its *Electric Vehicle Infrastructure and Education Program Application* (A.15-02-009) which is pending before the Commission.[32] Additionally, deployment of DERs in Angel Island could lead to effective consumer outreach if the National Park Service showcased the benefits of DERs to a wide ranging tourist audience.

ORA recommends that PG&E develop an optimal combination of DERs to meet the energy needs of Angel Island ahead of time. This will guide which portfolios to concentrate in. Finally, while generally supportive of the Angel Island micro-grid in concept, ORA requires further information to assess the cost effectiveness of the micro-grid and explore the possibility of utilizing other existing micro-grids in PG&E's service territory.

b) SCE Failed to Provide Sufficient Detail for the Commission to Establish the Reasonableness of its Orange County Area Micro-Grid Project.

SCE only identified Orange County as the location of its micro-grid. SCE states that it is:

> currently in discussion with multiple customers…to engage their interest in participation in a micro-grid project and to obtain a firm commitment. If a commitment cannot be obtained in the Orange County area, SCE will leverage a location with existing resources…in another part of SCE's service territory that has potential for expansion to support the demonstration of a micro-grid.[33]

Since SCE's micro-grid project lacks a clear scope of work – including a budget, a timeline, and proposed location, SCE failed to establish the reasonableness of its proposed micro-grid project.

c) ORA Requires Additional Information to Evaluate the Reasonableness of SDG&E's Borrego Springs Micro-Grid.

According to SDG&E, the Borrego Springs micro-grid project seeks to reinforce the existing micro-grid in Borrego Springs, a relatively isolated community in SDG&E's service

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[32] In A.15-02-009, PG&E proposes to install electric infrastructure to support electric vehicle charging stations.

[33] SCE DRP, p. 109.

territory.[34] The current micro-grid provides backup power in the event of an emergency. SDG&E proposed to add $14.7 million worth of substation-connected energy storage, distributed generation, merchant photovoltaics (PV), and customer PV in order to run the micro-grid for reliability purposes. According to SDG&E, the Borrego Springs micro-grid was selected:

> after a thorough investigation of potential sites, which included factors such as historical reliability, PV penetration, land availability, and community acceptance….The geographical location, isolation, rugged terrain, and preponderance of severe weather events around this community has presented reliability challenges over the years. Local DER presented an opportunity to improve the reliability.[35]

ORA generally supports SDG&E's rationale for selecting the Borrego Springs micro-grid as a remote town served by a single sub-transmission line.[36] However, additional details are needed regarding the selection of this micro-grid, compared to other potential micro-grid projects, to thoroughly understand the methodology for choosing this particular micro-grid.

3. Demonstrate New Business Utility Model for DER Integration.

SDG&E proposes an optional sixth project to "Demonstrate New Business Utility Model for DER Integration." This project is intended to "foster increased collaboration between the customer and the utility and enable increased DER integration."[37] If approved, SDG&E plans to:

> identify a specific location on the distribution system where 1) a capacity-related upgrade is needed, has been identified, and is currently included in SDG&E's distribution plan and capital budget…and 2) an aggregation of behind-the-meter storage resources with sufficient control mechanism could potentially provide a suitable substitute for the conventional upgrade project.[38]

According to SDG&E this:

> pilot potentially creates fewer distribution-level infrastructure projects on which utilities like SDG&E would earn a traditional return. Therefore, for this pilot to be successful and scalable, it is necessary to incorporate and validate a new, performance-based utility incentive that partially replaces lost earning and enables

[34] SDG&E DRP, p. 82.

[35] *Id.*

[36] See https://building-microgrid.lbl.gov/borrego-springs.

[37] SDG&E DRP, p. 85.

[38] *Id.* at p. 86.

> utilities to be active partners in identifying and incenting optimal location of DER solution on the distribution grid.[39]

ORA generally supports SDG&E's optional D&D Project to demonstrate direct incentives and tariffs as a new utility business model for DER integration. ORA also supports SDG&E's initiative in proposing a new tariff but the discussion of a new utility business model should be contemplated for all utilities either in a separate phase of the DRP or in a separate proceeding.

D. Identify Additional Utility Spending to Integrate DER.

P.U. Code Section 769 (b)(4) requires IOUs to identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers. Under P.U. Code Section 769 (c) the Commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The Commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

1. PG&E Should File a Supplement to the DRP Showing its Planned Investments Prior to Commission Reasonableness Review.

PG&E failed to comply with the Guidance and P.U. Code Section 769(b)(4) because it makes only general references to program spending mechanisms with no description of individual programs or associated costs.

ORA recommends that PG&E comply with the requirements of P.U. Code Section 769 and the Guidance by providing a supplement to this DRP that describes the specific actions and investments it intends to make along with cost estimates for all demonstration and deployment projects. It is only upon such a showing that the Commission can make a determination of the reasonableness of PG&E's spending. Review of costs under the General Rate Case (GRC) cannot address an IOU's spending in the context of the Commission's broader public policy goals to ensure efficient integration of DERs and meeting California's public policy objectives to reduce greenhouse gas emissions through DER integration.

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[39] SDG&E DRP, p. 87.

2. The Commission Must Review the Reasonableness of SCE's Request for Grid Investments.

SCE identifies grid modernization investments in distribution automation, substation automation, communication systems, technology platforms and application and grid reinforcement, with a total cost ranging from $1.405 billion to $ 2.585 billion. SCE:

> requests permission to file a tier 1 advice letter establishing a Distributed Energy Resources Memorandum Account (DERMA), which would track spending on grid modernization and grid reinforcement that SCE may incur prior to its next GRC.[40]

SCE's investment projections only account for spending in the 2018 GRC. Thus, by the time the Commission renders a decision in this DRP proceeding in 2016, SCE's investments for 2015 and 2016 can be only retroactively approved.[41] While ORA agrees that some DER integration costs are necessary, ORA finds that SCE's plan to expedite DER integration prior to a Commission decision on DER integration costs (1) denies the Commission an opportunity to review the DRPs and implementation costs for reasonableness and (2) evades the Commission's intent of using demonstration and deployment plans to inform the distribution planning process, and specific decisions to defer infrastructure investment.

Also, if SCE recovers up to $ 2.585 billion in distribution upgrades in the 2018 GRC, SCE will be well on the path to nonstrategic DER investment spending. In a 2012 study, SCE anticipated DER integration costs could result in $4.5 billion in transmission and distribution system upgrades but could also be reduced to as low as $2.1 billion if DER were implemented in a guided manner that incorporated location.[42] The upper limit of SCE's current DER investment estimates of $ 2.858 billion is already above the $2.1 billion projected cost to integrate DERs strategically.

ORA recommends that the Commission review SCE's investments for reasonableness in a ratesetting track of this proceeding and also recommends that the Commission include a cost cap on DER integration spending in this DRP cycle. A cap will ensure that SCE takes a phased approach to DRP investments. A phased approach should lower overall integration costs by

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[40] SCE DRP, p. 202.

[41] While ORA has not yet analyzed this, the proposal may trigger the prohibition against retroactive ratemaking.

[42] SCE, *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System* (May 2012).

allowing smart grid technologies, which are expected to mitigate some of the potential costs of DER, to develop and be implemented through uniform standards. A phased approach will also ensure that grid modernization and reinforcement is not created on distribution lines too early before it is useful. This is important. Ratepayers should not fund investment in technologies which are quickly stranded. A phased approach will save ratepayers money by potentially leapfrogging emerging technology on portions of the distribution system which require reinforcement at a later date.

3. SDG&E Needs to Clarify its Investments and the Commission Must Review the Investment Plan for Reasonableness and Cost-Effectiveness.

SDG&E identifies DER-related investments as "examples of investments" which are either "expansions of existing programs or projects" or "completely new initiatives."[43] The following summarized SDG&E planned investments:

- SCADA expansion to increase reliability, visibility and automated control of circuits;
- Identify the phase of each conductor on a three-phase feeder as well as individual phase branches for safety reasons;
- Upgrade half of its 4 kilovolt (kV) circuits to 12 kV circuits to improve reliability and reduce maintenance costs;
- Implement phasor measurement units (PMU) to allow for improved transient control, fault detection/isolation and the ability of the system to accommodate higher penetration of DERs; and
- Investment in new analytics tools to model infrastructure on a near-real-time basis.[44]

SDG&E includes no cost estimates for any of its planned investments and requests a memorandum account to begin tracking costs.[45]

ORA is unable to review the reasonableness of SDG&E's investments without additional information on project cost estimates or a timeline for implementation, which should be provided to ORA in the context of a ratesetting proceeding. Also, SDG&E's proposals include infrastructure investments and ORA finds no evidence of deferred distribution upgrades or

[43] SDG&E DRP, p. 124.

[44] *Id.* at pp. 123-129.

[45] *Id.* at p. 123.

associated ratepayer savings. The Commission should require SDG&E to provide cost estimates, a timeline for implementation, and a cost cap as a condition of approving SDG&E's DRP-related investments. Otherwise, SDG&E may be handed a blank check, signed by the ratepayers.

E. Coordination with General Rate Cases.

P.U. Code Section 769(b)(4) requires IOUs to "[i]dentify any additional utility spending necessary to integrate *cost-effective* distributed resources into distribution planning consistent with the goal of *yielding net benefits to ratepayers*."[46] The Commission directed "the Utilities [] include a section in their DRPs where they describe what *specific actions or investments* may be included in their next GRCs as a result of the DRP process."[47]

1. PG&E Failed to Identify Specific Actions or Investments Recommended for DER Integration in the DRP or Coordinate Them With the GRC.

PG&E recommends that the Commission authorize "(a) DER Integration Capacity; (b) Voltage/Volt-Ampere Reactive (VAR) Optimization; and (c) other DRP-related investments and expenditures" through PG&E's 2017 GRC filing.[48] However, these references to technology are insufficient to comply with the Guidance's requirement to "describe *specific actions or investments*" or make a showing that such programs are *cost-effective*, as required under PU Code Section 796 (b)(4). The reference to "other related investments and expenditures" is particularly troubling because it is a catchall phrase which describes no particular program but provides a vehicle through which PG&E may conceivably recover expenses for any host of projects no matter how tangentially related they are to the DRP.

Also, footnote 83 of PG&E's DRP states that PG&E will file separate applications outside of the GRC "in exceptional cases."[49] Exceptions from the DRP will only be required in truly exceptional circumstances. It is inappropriate to raise the possibility of filing separate applications as a contingency from the onset, particularly since PG&E has provided so little detail on how it will evaluate and include investments in the GRC consistent with the Guidance.

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[46] (*emphasis added*).

[47] Guidance, p. 11 (*emphasis added*).

[48] PG&E DRP, p. 202.

[49] *Id.* at p. 201, fn. 83.

Rather than allow one-off funding requests as contemplated by PG&E, the Commission should establish a uniform funding process for all DRP related investments.

It is not plausible that PG&E is unable to estimate the costs of its programs, particularly since PG&E is scheduled to file its 2017 GRC application in September 2014, just two months after filing this DRP.[50] There has to be significant overlap between the two applications regarding distribution planning and expenditures.

PG&E's slim showing is coupled with a claim that "there is no need for separate Commission proceedings to update the utilities' approved DRPs."[51] This is diametrically opposed to the Guidance for biennial DRP updates,[52] and inconsistent with the goal of harmonizing DRPs across IOUs to facilitate review and implementation.[53]

The Commission should require PG&E to describe the scope of the three aforementioned programs with regard to their cost, specific investments, and the anticipated ratepayer benefits over current practices. In order to be processed through the GRC, the benefits resulting from DRP investments must be monetized or realized through reductions in expenses, capital expenditures, revenue requirements, and ultimately as reduced utility rates. That planning needs to start in the DRP before the Commission authorizes PG&E's implementation of these programs. Therefore, ORA recommends that PG&E provide that showing as part of the DRP application prior to Commission authorization of PG&E's spending request for its DRP.

2. SCE Coordinates DER Integration Costs But Not Ratepayer Savings in its GRC.

SCE's DRP correctly defines a process that integrates the overarching goals from the Guidance, tools to be developed, and funding through GRCs.[54] SCE also correctly acknowledges that a goal of the DRP is to defer traditional investments. SCE also complies with the Guidance requirement to discuss the "specific actions or investments [] included in their next

[50] PG&E is expected to file its 2017 GRC on September 1, 2015, per D.14-12-025, Table 4, p. 42. The GRC filing is a massive tri-annual filing for which analysis and coordination with the DRP team should have begun early in 2015, if not earlier.

[51] PG&E DRP, p. 201.

[52] ACR, p. 5.

[53] "The DRPs filed should be consistent with each other in structure and content so they may be more easily compared and analyzed," ACR, pp. 1-2.

[54] SCE DRP, pp. 240-242.

GRCs as a result of the DRP process"[55] in Chapter 7 by including 17 grid modernization projects for which "SCE seeks…cost recovery authorization in SCE's 2018 GRC," which is expected to be filed September 1, 2016.[56] While it appears that these 17 projects are responsive to the Guidance, SCE should clarify this by providing a cross reference to Chapter 7 in Chapter 8, Section C.1., which explains how these grid modernization investments are consistent with its DRP.

However, SCE's GRC projects do not specifically address how DER can and should result in reduced expenses and in some cases avoided capital expenditures.[57] It is impossible to evaluate the cost-effectiveness of these programs, as required by P.U. Code Section 769(b)(4), without this showing. If the Commission fails to require SCE to quantify ratepayer benefits, it is likely that only revenue requirement increases will be adopted while associated cost savings in other programs will not be accurately recorded. Thus, rates will increase unnecessarily through double counting.

3. SDG&E Provides Only "Examples" of DRP Related Investments, and These Lack Sufficient Detail to be Consistent with P.U. Code Section 769(b)(4).

SDG&E's DRP is similar to SCE's in that it correctly defines that some DRP related projects will defer traditional investments and that these projects will be funded along with "traditional" infrastructure investments through its GRCs starting in 2017.[58] SDG&E also provides five "examples of investments in transmission and distribution infrastructure that SDG&E believes will accelerate the transition to the DER ready grid."[59]

However, the five projects listed appear to be only a few potential projects rather than a more comprehensive list of all projects under consideration by SDG&E. Further, SDG&E's examples do not identify the specific expenses and capital expenditures that would be reduced, deferred, or avoided, nor does it provide any quantitative support for these projects. It is

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[55] SCE DRP, pp. 240-243.

[56] D.14-12-025, p. 42, Table 4.

[57] As discussed above, increased reliability due to DER investments should reduce maintenance expenses incurred reestablishing service following an outage. Capital investments should also be avoided. For example, if fewer service crews are required, fewer service trucks would be required.

[58] SDG&E DRP, pp. 122-123.

[59] *Id.* at p. 124; *see also* pp. 124-129.

impossible to evaluate the cost-effectiveness of these projects, as required by P.U. Code Section 769(b)(4), without this showing. If the Commission fails to require SDG&E to quantify ratepayer benefits, it is likely, that as with SCE, only revenue requirement increases will be adopted while associated cost savings in other programs will not be accurately recorded. Again, ORA is concerned that double counting will cause rates to increase unnecessarily.

F. Modify IOU Integration Capacity Analysis to Reflect the impact of Smart Inverter Technology.

Under P.U. Code Section 769, the IOUs are required to:

> "(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation."

The Guidance breaks down the locational benefits and costs analysis into three parts: (a) integration capacity analysis, (b) optimal locational benefit analysis, and (c) DER growth scenarios.[60]

Under the integration capacity analysis, the Guidance requires IOUs to specify the DER hosting capacity on the distribution network down to the line section or node level, to be posted online and updated periodically.[61] Among other things, the Guidance also requires them to assess their current distribution system capability, together with any planned investments, within a two year period. The IOUs are also required to assess the state of DER deployment systemwide.

ORA generally supports the IOUs' integration capacity analysis. However, PG&E's hosting capacity limit analysis appears to be overly conservative under "an open, flexible and node-friendly network system"[62] because it assumes that DER connects without the ability to self-regulate. As illustrated in Figure 2-11 of its Application, PG&E's methodology assumes backflow and high voltage on the line near the 5 MW generator due to abnormal conditions.[63]

[60] Guidance, p. 3.

[61] *Id.* at p. 3.

[62] OIR, Appendix B, p. 8 (emphasis added).

[63] PG&E Application, p. 37.

However, PG&E fails to incorporate "More than Smart" technology whereby the DER can also adapt to system conditions. Under its integration capacity analysis, PG&E should also consider the situation whereby the 5 MW generator can reduce output to 1 MW under abnormal conditions.[64] Rather than limiting the DER's nameplate capacity, ORA recommends developing an operating procedure or protocol that allows DER to respond to system conditions under abnormal or emergency situations.

Also, ORA generally supports PG&E's utilization of integration capacity analysis to support interconnection rules.[65] However, ORA recommends PG&E validate the integration capacity analysis methodology prior to using it to set interconnection evaluation criteria such as Rule 21's Screen M.[66]

G. Modify the Locational Value Analysis to Adjust for the Assumption that Over-Generation can Occur Due to Both Conventional and Renewable Resources.

The Guidance requires IOUs to develop "a unified locational net benefits methodology consistent across all three utilities that is based on the Commission approved E3 Cost-Effectiveness calculator but enhanced to explicitly include location-specific values."[67]

ORA generally supports the locational value analysis, with the exception of one over-generation assumption. IOUs should not attribute over-generation at night solely to DERs. In ORA's view, over-generation at night can also occur because bulk system or utility-scale power generation cannot or does not shut down in order to maintain a minimum load level. Thereby, both DER and bulk generation contribute to over-generation issues.

1. Data Access - ORA Supports SCE's Proposal to Create a Data Access Working Group and Recommends ADR Oversight.

Pursuant to the Guidance, the Commission directed the large IOUs to address data access issues as part of their respective DRPs. Particularly, the large IOUs' DRPs must focus on three

[64] PG&E Application, p. 37.

[65] *Id.* at p. 61.

[66] Screen M is part of the Rule 21 interconnection process which applies to Aggregate generation 15% larger than line section peak load.

[67] Guidance, p. 4.

main issues: (1) proposed sharing of distribution system and DER data (2) procedures for data sharing; and (3) grid condition and smart meter data.

The IOUs' DRPs state that the Commission should align any data sharing processes and procedures with current state, federal and utility industry data access policies and procedures.[68] For example, PG&E's DRP states,

> "PG&E's enhanced distributed planning data access initiatives will comply with CPUC and other regulatory agency rules and regulations, including the CPUC's customer data privacy and energy data access rules and FERC critical infrastructure rules."[69]

Similarly, SCE states that it believes data should be shared, in part, when:

> "[d]oing so would not violate Commission rules, state or federal laws, regulations or any other applicable requirements protecting customer privacy, trade secrets, proprietary information, grid reliability and security, or public safety, including the law and rules in Appendix F [of SCE's DRP]."[70]

ORA agrees that the DRPs should not be a vehicle to revisit and relitigate the Commission's established data privacy and access rules.[71]

In its DRP, SDG&E also emphasizes the need to keep its customers and infrastructure safe and secure. SDG&E cautions that as "ownership and location of electrical distribution assets expands associated with an increasing penetration of DER, existing physical security threats will be exacerbated and new threats introduced."[72] Therefore, SDG&E argues that certain information should not be disclosed because it could jeopardize physical security. SDG&E emphasizes information security and states that:

> all data shared as a result of the CPUC-approved DRPs will be data that can be classified, e.g., data that has already been collected and stored by SDG&E from data-providing assets. No data will be transmitted near real-time, in real-time, nor directly from an SDG&E-owned, operated, or controlled asset.[73]

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[68] SDG&E DRP, p. 89.

[69] PG&E DRP, p. 160.

[70] SCE DRP, p. 113.

[71] *See,* Comments of the ORA on the Assigned Commissioner's Ruling Re Draft Guidance For Use in Utility AB 327 (2013) Section 769 Distribution Resources Plans, p. 11[filed December 12, 2014; in R.14-08-013.

[72] SDG&E DRP, p. 90.

[73] *Id.* at p. 93.

ORA agrees that the safety and security of the IOUs' customers and infrastructure is a critical issue, and going forward both will require constant attention.

SCE's DRP identifies multiple issues that may require consideration in these proceedings. To address these issues, SCE proposes parties hold a series of workshops and/or working groups to discuss, in detail, the possible data access cases.[74] In Appendix G of its DRP, SCE provides a list of proposed data access policies and workshop issues for consideration. Considering the numerous issues raised by SCE, ORA agrees there may be value in holding a series of workshops and/or working groups. The Commission took a similar approach in Rulemaking ("R.") 08-12-009 when it identified a number of "use cases" that provided deferring levels of third party access to customer data. In that proceeding, the Commission also required parties to draft a "Working? Group Report" to identify the issues, and parties' views and recommendations.[75] The Commission should apply a similar approach here.

ORA also recommends the Commission utilize the existing Alternate Dispute Resolution ("ADR") process to facilitate the resolution of any the Data Access issues identified by workshops or working group. The ADR process has been valuable when addressing complex issues with multiple party input (*See*, R.08-11-005). Thus, ORA agrees with SCE that workshops/working groups would be useful to address the data access issues raised in the Guidance and further outlined in Appendix G of SCE's DRP.

H. Safety – IOUs Should Provide a List of Technology-Specific Safety and Reliability Standards Along with a Process for Compliance with Existing Standard; PG&E Should Also Provide Information on Community Education and Outreach for Safety.

The Guidance requires IOUs to include a "[c]atalog of potential reliability and safety standards that DERs must meet and process for facilitating compliance with [existing] standards."[76] However, the IOUs did not sufficiently provide reliability and safety standards to deploy DERs and did not include a process for facilitating compliance with existing standards. PG&E referred to its Distribution Interconnection Handbook as a resource for interconnection, fault duty contribution, isolation requirements from the grid, harmonic distortion, and voltage

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[74] SCE DRP, pp. 124-125.

[75] *See also Id.* at pp. 126-127.

[76] Guidance, p. 9.

regulation requirements.[77] Although PG&E's Interconnection Handbook does address safety requirements associated with DER interconnection, ORA notes it is old and in the process of being updated by PG&E so the Commission should be cautious in relying on it..[78]

ORA recommends that SCE and the other IOUs detail technology specific safety standards, if they exist, in their respective DRPs. A suggested format to provide this information could be a matrix or table that outlines specific DER technologies (e.g. vehicle to grid energy storage, lithium ion energy storage devices, etc.) and associated safety standards. A description of technology-specific safety standards will inform the Commission, developers, and stakeholders regarding the risks that specific DERs may impose. For example, the deployment of energy efficiency technologies, including variable speed drives or liquid diode emitting (LED) lights, may present a lower safety risk in comparison to EV charging stations that may result in thermal overloading of transformers due to overloading of distribution circuits.

Also, ORA recommends that the Commission order PG&E to describe a process in its DRP for ensuring compliance with safety standards related to DER deployment. If these compliance processes are not implemented, DER could present hazardous conditions that impact the public and worker safety. In addition, DER devices may not be used or useful due to failure to adhere to safety protocols, including inspections and audits.

Under the Guidance, IOUs are also required to provide a description of education and outreach activities to disseminate safety information.[79] While SCE is prepared to share best practice information with local government authorities and SDG&E will provide on-going training for first responders and engage in community outreach to homeowners' associations[80], PG&E did not provide examples of how it would educate local permitting authorities aside from coordinating the DER interconnection process. [81]

ORA suggests that the Commission require PG&E to provide a description of policies and procedures to communicate DER safety information to local safety authorities (e.g. local

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[77] PG&E DRP, p. 174.

[78] PG&E Distributed Generation Interconnection Handbook, http://www.pge.com/en/mybusiness/services/nonpge/generateownpower/distributedgeneration/interconnectionhandbook/index.page.

[79] Guidance, p. 10.

[80] SDG&E DRP, pp. 115-116.

[81] PG&E DRP, p. 179.

government party public works departments). ORA believes that outlining a process for educating and informing local authorities regarding DER hazards is critical and will minimize the risk that DERs (e.g. behind the meter energy storage devices, including lithium ion batteries, which may not be under utility purview) may cause harm to workers and the public.

I. Phasing of Next Steps.

1. The Commission Should Order a Separate Phase of the DRP to Begin the Stakeholder Driven DER Policy Development, Which Would Consider Alternatives to the Current IOU Procurement Process for DER Procurement Policy and Mechanism Development.

Under Phase 2b, the Guidance requires the IOUs to participate in a stakeholder-driven DER procurement policy and mechanism development process.[82] The stakeholder-driven process is intended to create "a plan for how these deployment scenarios would impact distribution planning and identify gaps that exist in current plans to support achieving each of the scenarios." Under the Guidance, the IOUs' affirmative actions are limited to "updating system status in terms of DER deployment and associated system impacts."[83]

The IOUs provided different responses on their role under Phase 2b. PG&E is silent on participation in a stakeholder-driven process and states that it intends to "focus on a DER distribution deferral mechanism." SCE adopts the Guidance in whole.[84] SDG&E plans to retain control of DER integration planning through solicitations, adapting its least-cost best-fit energy procurement methodology to distribution-level planning.[85]

SDG&E's proposal to conduct solicitations as the sole means of procuring DERs for distribution-level planning locks in a centralized control mechanism which may limit DER integration. It does not make sense to automatically transpose the same mechanisms utilized in energy procurement for distribution system planning. Traditional utility-run RFOs occur on an expanded timeline suitable for traditional gas-fired generation, which requires a 10 year lead time to build and results in infrastructure suitable to operate for thirty years or longer. In contrast, many DERs can be online in less than a year. Also, procurement RFOs generally take

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[82] Guidance, p. 12.

[83] *Id.* at p. 13.

[84] SCE DRP, p. 246.

[85] SDG&E DRP, pp. 139-142.

many months to years to conduct, followed by an 18 month application process for Commission's approval. This model is not necessarily suitable to the rapidly evolving needs of distribution-level planning, which involves small, cheaper resources which may become obsolete within the decade.

Also, utility-run solicitations require sophisticated bidders who are able to respond to specific IOU requirements and submit bids within a narrow time-window. In contrast, many DER interconnections are initiated by residential and retail customers unacquainted with the intricacies of energy procurement policy.

In addition, the increased overhead of bidding and utility oversight raises the costs of the final market product for ratepayers. Unlike traditional procurement RFOs where a handful of bids are contracted, a DER-based deferral may potentially involve hundreds of individual accounts requiring advanced telemetry for utilities to control or operate through third parties. Tariffed structures avoid some of the overhead by creating incentives to drive customer participation or imposing restrictions on DER operation based on predetermined parameters rather than relying on IOU command and control of individual DER resources.

Finally, SDG&E's proposal to focus on RFO or distribution deferral, while proposing no new tariffs or other incentives, creates a model allowing DERs to interconnect without optimizing the integration of DERs. Subsequent RFOs create patches to cure problems created by DER integration rather than creating a structure that encourages integration during the initial grid interconnection through proper pricing mechanisms and other incentives.

SDG&E's proposed RFO process also presupposes that the IOUs will be the distribution system operators and prematurely approves a distribution planning mechanism which may be inconsistent with the stakeholder-driven policy and procurement mechanism envisioned by the Commission. Therefore, ORA recommends rejecting SDG&E's proposal to continue DER procurement solely through solicitations in Phase 2b. ORA also recommends that the Commission begin the process of creating the stakeholder-driven process by initiating a separate phase of this consolidated proceeding. It will take time to properly scope out the issues for the stakeholder-driven process and even more time to develop the DER integration policy and mechanisms envisioned under Phase 2b.

2. ORA Supports SDG&E's Contention That a Distribution System Market May be Unnecessary (Phase 2b)

Under Phase 2b, the Guidance states that the stakeholder-driven DER procurement and policy mechanism will include the development of Distribution System Markets that can support grid service transactions. SDG&E's DRP states that the need for a distribution market can be eliminated through the "three Ps: price, program and procurement."[86] Without expressing an opinion on the necessity of a Distribution System Market, ORA agrees with SDG&E to the extent that the Commission needs to be flexible in its implementation of the next steps. The Distribution System Market may no longer be necessary if DERs are able to participate effectively in CAISO's current and future markets, such as through the aggregated products currently contemplated in the Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiative.[87]

3. ORA Supports SCE's Proposal to Create Distribution Procurement Review Group to Review Each Utility's Deferral Framework.

SCE suggests creating a distribution planning review group to "review each utility's application of the deferral framework."[88] SDG&E also suggests creating a Distribution Procurement Review Group. Utility DER procurement should be a last resort. Nonetheless ORA supports SCE and SDG&E's proposal to create a distribution planning review group to review each utility's application of the deferral framework.[89]

V. CATEGORIZATION, HEARINGS, AND SCHEDULE

On July 1, 2015, the IOUs filed Applications with their DRP proposals (A.15-07-002, et al. or Applications). SCE, PG&E and SDG&E requested the Applications to be categorized as quasi-legislative, while Bear Valley Electric Service, Liberty Utilities LLC, and PacifiCorp requested the Applications to be categorized as ratesetting. The Applications were preliminary categorized as ratesetting. On July 27, 2015, the Administrative Law Judge

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[86] SDG&E DRP, p. 142.

[87] *See* CAISO, Energy Storage and Distributed Energy Resources (ESDER) Stakeholder Initiative, Issue Paper and Straw Proposal (July 30, 2015).

[88] SCE DRP, p. 247.

[89] *Id.*

ruled that the OIR and Applications should be consolidated (jointly referred to as the consolidated proceeding).[90] On August 14, 2015, the ALJ issued a ruling that proposed re-categorizing these proceedings as quasi-legislative.[91] The ALJ also stated "parties may make a recommendation as to the final categorization of the proceeding."[92]

ORA appeals the proposed categorization of the consolidated proceeding as quasi-legislative. ORA opposes categorization of the entire proceeding as quasi-legislative, because both as a matter of law and sound policy, a portion of the issues presented in the consolidated proceeding merit categorization as ratesetting. Ratesetting cases are cases in which rates are established for a specific company, including, but not limited to, general rate cases, performance based ratemaking, and other ratesetting mechanisms.[93]

The categorization of quasi-legislative or ratesetting is a distinction with significant differences. Generally speaking, in ratesetting proceedings an IOU bears the burden of proof that its proposal is reasonable. The Commission has noted that there is no distinction between types of ratemaking cases with respect to the utility's burden of proof:

> The inescapable fact is that the ultimate burden of proof of reasonableness, whether it be in the context of test-year estimates, prudence reviews outside a particular test year, or the like, never shifts from the utility which is seeking to pass its costs of operations onto ratepayers on the basis of the reasonableness of those costs.[94]

In addition, the Public Utilities Code Section 1701.3(c) and Article 8 of the Rules of Practice and Procedure prohibits ex-parte communications in ratesetting proceedings except in several specified exceptions.[95] In contrast, in quasi-legislative proceedings, the Public Utilities Code and the Rules of Practice and Procedure do not impose the same burden on parties and ex-parte communications which are allowed without restriction or reporting.[96]

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[90] *Administrative Law Judge's Ruling 1) Consolidating Proceedings; 2) Setting Prehearing Conference, and 3) Granting Motion For Extension of Time*, dated July 27, 2015, p. 4.

[91] *Administrative Law Judge's Ruling re Preliminary Categorization of A.15-07-002*, dated August 14, 2015.

[92] *Id.*

[93] P. U. Code § 1701.1(c)(3).

[94] Opinion Regarding Proposed General Rate Increase, Decision (D) 04-03-034, p. 7.

[95] Rule 8.3(c) of the Rules of Practice and Procedure of the Commission.

[96] Rule 8.3(a) of the Rules of Practice and Procedure of the Commission.

The different treatment of ratesetting and quasi-legislative proceedings is grounded on an important public policy objective of providing ratepayers due process in contested proceedings affecting rates. If the proceeding may increase rates, Public Utilities Code section 454 requires hearings. Utility applicants must demonstrate, and the Commission must find, that the proposal results in just and reasonable rates, and section 1701.3 requires parties be given a higher level of due process.

A. The Portion of the Consolidated Proceeding that Requires Commission Approval of DRP Related Costs Should be Categorized as Ratesetting.

The consolidated proceeding includes a blend of issues that are clearly quasi-legislative, and other issues that will affect rates, and thus should be categorized as ratesetting. Indeed, the Commission acknowledges that the DRPs include issues affecting rates and states that "[o]ne of the most critical components of the DRP process will be its interface with the [IOUs] General Rate Cases."[97]

The IOUs are required "to propose [Distributed Energy Resources]-focused demonstration and deployment projects."[98] As part of the demonstration and deployment projects, they are required to "include any expected cost recovery for these demonstration projects as part of their DRP applications, including any specific proposals related to minimum cost thresholds requiring Commission approval."[99] The IOUs are also required to identify utility investment in grid-modernization,[100] which could include significant costs. Recategorizing the entire proceeding as quasi-legislative cedes the Commission's authority to evaluate the IOUs' proposals for reasonableness and to modify these proposals "to minimize overall system costs and maximize ratepayer benefits from investments in distributed resources" under Public Utilities Code section 769 (c). The Commission's approval of IOUs' costs without a reasonableness review is unambiguously a ratesetting act that will likely

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[97] *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning*, dated February 6, 2015, Attachment p. 11.

[98] *Id.*, Attachment p. 4.

[99] *Id.*, Attachment p. 6.

[100] *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning*, dated February 6, 2015, p. 4 and Attachment p. 10.

increase rates at least in the short term. Thus, it is inappropriate and a violation of section 454 to categorize the entire consolidated proceeding as quasi-legislative.

Per Rule 7.1(e)(2), in a proceeding, such as this consolidated proceeding, that "may fit more than one category…the Commission…may divide the subject matter of the proceeding into different phases…" Moreover, per Rule 7.1(e)(2), when there is doubt as to the appropriate categorization, the ratesetting rules are applied. As it is clear that the consolidated proceeding has ratesetting issues, ORA respectfully requests the Commission, as a matter of law, to reclassify a portion of the consolidated proceeding and create a ratesetting phase or track to address the costs in the demonstration and deployment projects and its implementation, and the utility investment in grid-modernization costs.

Reclassifying the cost recovery portions of this proceeding also has other policy benefits. A concurrent ratesetting track of the proceeding would expedite the review process, because there would be no need for a separate application to review the reasonableness of costs. A ratesetting phase or track is appropriate because the Commission will review the reasonableness of the demonstration plans and grid investment plans on an individual basis; not as a class of entities.[101]

It also makes sense to approve the DRPs in a manner analogous to the adoption of the Smart Grid Deployment Plans, which the DRPs augment. The Commission approved the Smart Grid Plans as policy documents while requiring cost recovery through subsequently filed applications or GRC recovery.[102] As held in the Smart Grid Proceeding, approval of the DRP conceptually in a quasi-legislative proceeding should not create a presumption of reasonableness for cost recovery.[103] Requiring cost recovery for demonstration and deployment plans through a ratesetting proceeding is also consistent with Commission

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[101] As the Commission has previously stated, "We consider each such proposal on its merits and weigh the amount of public good, the cost to ratepayers, and the availability of alternative financing vehicles, among other things, in determining whether or not to authorize such investments." D.12-05-014, p. 11.

[102] In D.10-06-047 (Smart Grid Decision), the Commission stated "[PG&E, SCE, and SDG&E] each shall seek approval of Smart Grid investments either through an application and/or through General Rate Case." D.10-06-047, OP 14, p. 144. In deciding this, the Commission argued "either a review in a GRC or in an application can provide sufficient Commission oversight of an investment." D.10-06-047, p. 95.

[103] *Scoping Memo and Ruling of the Assigned Commissioner*, In the Matter of the Application of SDG&E on its Smart Grid Deployment Plan and Related Matters, dated October 3, 2011, p. 11, http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=48102, (The Smart Grid Deployment Plans adopted by the Commission will provide guidance, not a presumption of reasonableness.)

approval of research projects under the Electric Program Investment Charge (EPIC) program, where IOUs file as separate applications on a triennial basis.[104]

ORA thus recommends that the consolidated proceeding remain categorized as quasi-legislative except for the following issues, which should be categorized as ratesetting and held on a concurrent schedule:

- Cost recovery of the demonstration and deployment projects,
- Cost recovery of the grid modernization proposals, and
- Cost recovery of any other portion of the DRPs that affect implementation costs and rates.

If the Commission proceeds with designating the consolidated proceeding as quasi-legislative, then ORA respectfully requests the Commission clarify how it will address cost recovery in the proceeding as stated in the Guidance.

B. ORA Anticipates that Workshops and Potentially Hearings are Needed.

PG&E, SCE and SDG&E propose workshops to incorporate public comment on their respective DRPs.[105] ORA supports the proposal to hold workshops and recommends topics in this Protest, as summarized in Section III.[106] In addition, ORA requests the Commission require a workshop report and allow parties a meaningful opportunity to comment or contribute a workshop report through comments.

PG&E, SCE and SDG&E anticipate that hearings will not be needed.[107] ORA disagrees. As discussed above, the Commission must conduct a reasonableness review because the DRP envisions spending for D&D Projects as well as grid modernization and reinforcement, which will cost ratepayers billions of dollars. In the event of hearings, ORA

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[104] *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, Application of the California Energy Commission for Approval of Electric Program Investment Charge Proposed 2012 through 2014 Triennial Investment Plan, dated January 7, 2013, p. 18, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M042/K158/42158984.PDF; *See also*, *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, Application of the California Energy Commission for Approval of Electric Program Investment Charge Proposed 2015 through 2017 Triennial Investment Plan, dated July 28, 2014, pp. 3, 10, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M099/K767/99767903.PDF.

[105] PG&E Application, p. 2; SCE Application, p. 7; SDG&E Application, p. 12.

[106] *See* PG&E Application, p. 2; SCE Application, p. 7; SDG&E Application, p. 12.

[107] PG&E Application, p. 2; SCE Application, p. 7; SDG&E Application, p. 12.

recommends that the Commission adopt a schedule that allows parties additional time to conduct discovery on the complex issues raised in this application.[27]

ORA's proposed consolidated schedule, with due dates bolded in black, is presented below in Table 1.

Table 1
ORA's Proposed Schedule

Action	**Date**
Application Filed	July 1, 2015
CPUC Notice in Daily Calendar	July 3, 2015
Protests	**August 31, 2015**
Reply to	**September 15, 2015**
Prehearing Conference	**September 23, 2015**
Scoping Memo Issued	**October 14, 2015**
Track 1(Quasi-Legislative)	**Track 2 (Ratesetting)**
Workshops **October - November 2015**	Intervenor Testimony **November 23, 2015**
Workshop Report **January 8, 2015**	Rebuttal Testimony **December 15, 2015**
Opening Comments **February 5, 2015**	Hearings (if necessary) **January 11-15, 2015**
Reply Comments **February 19, 2015**	Concurrent Opening Briefs **February 1, 2015**
	Concurrent Reply Briefs **February 15, 2016**
Proposed Decision	**May 2016**

Comments of Proposed Decision Due[108]	**June 2016**
Reply Comments Due	**June 2016**
Commission Decision Adopted	**July 2016**

VI. CONCLUSION

ORA respectfully submits this Protest and recommends that the Commission adopt ORA's recommendations, as summarized in Section III above, before approving the IOUs and SMJUs DRPs. In particular, the Commission should require more cost information in ratesetting tracks to avoid approving these costs without a reasonableness review and giving the utilities a blank check signed by ratepayers.

Respectfully submitted,

/s/ JAMES RALPH

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August 31, 2015

[108] ORA recommends one proposed decision which will include policy discussions related to the compliance of IOUs under the Guidance and section 769 as well as the reasonable of cost for the deployment and demonstration plans and any funding requested as part of the DRP.